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CAPACITY MARKET DESIGN: MOTIVATION AND CHALLENGES IN ALBERTA'S ELECTRICITY MARKET

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SUMMARY

Alberta's electricity market is currently undergoing a period of substantial transition. The province should proceed with caution as it switches from an energy-only electricity market to a capacity market by 2021. Many other jurisdictions have already made the changeover and Alberta can learn from their experiences in order to avoid common mistakes and pitfalls that can arise with the deployment of a capacity market.

There were growing concerns that the existing electricity market structure would not attract sufficient investment from conventional generation (e.g., natural gas) due to the increased penetration of zero marginal cost renewable generation. As a result, the Alberta government has chosen to transition to a capacity market. For consumers, a capacity market aims to ensure there is sufficient investment in new generation capacity to "keep the lights on" and reduce price swings in the wholesale market. The capacity market will also help the province meet its goals for attracting investors and transitioning away from its dependence on coal-fired electricity generation.

However, a switchover is not as simple as it sounds.

In an energy-only market, firms are paid solely based on the provision of electricity in hourly wholesale markets. In capacity markets, electricity-generating firms are also paid for providing generation capacity, reflecting the potential to provide electricity at some point in the future. While capacity markets can help ensure there is a reliable supply of electricity, there are several challenges in the implementation of capacity markets. This paper discusses the motivation for the adoption of capacity markets, highlights challenges regulators face when implementing this market design in the context of Alberta, and summarizes the key trade-offs associated with energy-only versus capacity market designs.

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Relative to an energy-only market, a capacity market is more complex and requires that regulators specify numerous parameters that are essential to the functioning of the market. An essential, but often controversial component is the formulation of the capacity demand curve. A capacity demand curve for Alberta has to be carefully designed to deal with uncertainties in demand growth, given that Alberta's electricity demand is closely interconnected with the ups and downs of global crude oil prices.

Consideration must be given to the perspective of outside investors who – as in any area of economic interest – are wary about uncertainty. Political and regulatory uncertainty can undermine the success of a capacity market. This potential for investor hesitancy could result in incumbent firms, familiar with investing in Alberta, seizing a larger share of the market in an already historically concentrated environment. It is critical that policymakers establish a clear and well-defined trajectory for the future of Alberta's electricity market design as a whole, not just its capacity market.

The capacity market is not a panacea for the potential downfalls of an energy-only market. There are trade-offs associated with both energy-only and capacity market designs. Energy-only markets are arguably more economically efficient with cleaner price signals. However, with political constraints on electricity price-spikes and the expansion of renewables, there is more uncertainty in an energy-only market's ability to promote investment. A capacity market provides more certainty in terms of generation resource adequacy, but at a potentially higher cost. Despite these tradeoffs, capacity markets are unambiguously more complex. This places a heavy burden on regulators to carefully and correctly set critical capacity market parameters that can have substantive impacts on prices and the associated economic signals.

INTRODUCTION

Alberta began its transition from a regulated electricity market to an energy-only market design in 1996.[1] In an energy-only market, electricity generators are compensated for the energy services they provide in hourly markets. In this setting, generators rely on high prices that occur when supply conditions are tight in order to recover their large fixed costs of investing in a generation facility. This scarcity pricing is the primary instrument to motivate capacity investment in order to facilitate competition in hourly energy markets and ensure a reliable supply of electricity (Hogan, 2005).

In recent years, Alberta's electricity industry has faced substantial changes in government policies and economic forces. In 2016, the Alberta government announced several policies that increase the stringency of environmental regulation on carbon emissions, mandated a phase-out of over 6,250 MWs of coal generation capacity by 2030, and also announced a target to integrate 5,000 MWs of renewable generation capacity by 2030 via the Renewable Electricity Program (Government of Alberta, 2017a,b). At the same time, Alberta's wholesale electricity prices have declined substantially due in large part to the declining costs of natural gas, lower than forecasted demand and excess generation capacity (MSA, 2016b). The reduction in wholesale power prices, expansion of low-cost natural gas and implementation of more stringent carbon regulations have reduced the profitability of coal generation (Leach and Tombe, 2016; Brown et al., 2017). Further, there has been a dramatic decline in the cost of wind and solar generation capacity investment (EIA, 2017).

In principle, Alberta's existing energy-only market design could be utilized to motivate investment by allowing wholesale electricity prices to rise to sufficiently high levels when supply conditions are tight. However, policy-makers were concerned that Alberta's existing market design would not provide sufficient incentives for investment in electricity generation capacity (AESO, 2016a). These reliability concerns were compounded by the anticipated retirement of Alberta's entire coal fleet by 2030, which represents 38 per cent of generation capacity and over 50 per cent of electric generation in Alberta (AUC, 2017). These concerns are driven by two primary factors. First, electricity price spikes are highly controversial in part because they may reflect firms' abilities to exercise market power rather than scarcity in available production capacity. Alberta's market currently has a price cap at $999.99 per MWh to limit the size of price spikes and profits from market power execution.[2] These price caps contribute to a "missing money problem" that limits critical scarcity pricing when electricity production capacity is constrained. These periodic scarcity prices are critical to motivate investment (Hogan, 2005). Second, there are growing concerns that expanded renewable capacity will suppress average electricity prices paid to non-renewable generators.

In November 2016, the Alberta government announced that it will introduce a capacity market in order to alleviate concerns that the existing energy-only market design will not ensure a reliable supply of generation capacity (Government of Alberta, 2016). Capacity markets provide a separate payment to electric generators for the potential to generate electricity (i.e., a payment for generation capacity), as well as a payment for the provision of energy in hourly markets (the energy payment). The Alberta government anticipates that the capacity market will begin its operation in 2019, with the first payments beginning in 2020/2021.

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[1] For a review of Alberta's energy-only market, see Olmstead and Ayres (2014) and Brown and Olmstead (2017).

[2] Other energy-only market designs have price caps in the range of US$9,000/MWh in Texas (Potomac Economics, 2016) and AU$13,800/MWH in Australia's National Electricity Market (AEMO, 2017).

Capacity market designs coupled with well-designed hourly electricity markets provide both a "capacity value" signal via the capacity market price and an "energy services" signal via the hourly energy market prices. These price signals aim to motivate cost-effective generation of electricity services at the hourly level, while simultaneously providing a long-run price signal to motivate the least-cost investment in generation capacity. In theory, the division of compensation into these separate components generates the same costs of providing electricity to consumers.[3] Further, capacity market designs are consistent with a competitive market structure and these markets have successfully promoted generation capacity investment in numerous jurisdictions (Bushnell et al., 2017).

However, capacity market designs are not without their critiques and drawbacks (e.g., see Newbery and Grubb (2016)). Capacity markets are very complex and rely on administratively set parameters. Capacity market outcomes can be highly sensitive to these parameters. Missteps in designing capacity markets can distort investment incentives, having long-term consequences on the structure of electricity markets and the important price signals that are critical in a well-functioning electricity system. For example, one critical concern is that regulators have an inherent conservative bias to procure more capacity than necessary (Newbery, 2015). This can lead to excessive capacity payments. In addition, the types of resources that can provide the capacity product in the capacity market are often the subject of debate. The capacity value that renewable resources and imports from neighbouring provinces provide is highly controversial. Errors in the definition of the capacity value of resources distort firms' investment incentives.

This article proceeds as follows. First, I summarize Alberta's existing market structure and the projected evolution of the market. Second, I discuss the trade-offs associated with both energy-only and capacity market designs. This provides insights into what motivates governments to adopt either market design. Third, I summarize typical aspects of capacity markets, as well as the challenges other jurisdictions have had to address when implementing a capacity market design. These experiences help provide regulators and policy-makers in Alberta with a roadmap on how to design a capacity market and avoid common mistakes. Throughout the discussion, I emphasize the unique Alberta-specific attributes that need to be considered when implementing a capacity market design.

ALBERTA'S ELECTRICITY MARKET STRUCTURE AND EVOLUTION

Table 1 provides a snapshot of Alberta's market structure, the distribution of capacity and generation by technology, and the distribution of demand by consumer group (MSA, 2016a, AUC, 2017). Generation capacity and observed generation output are dominated by coal and natural gas technologies making up approximately 82 per cent and 90 per cent in 2016, respectively. In early 2016, the market was concentrated with two-thirds of generation capacity offered into wholesale markets by the five largest firms in the market, with a fringe of over 25 competitors owning the residual capacity. The offer control of coal assets in the province is changed due to the termination of purchase power arrangements (see Balancing Pool (2017) for more details). This will change the nature of market competition going forward.

[3] For a formal demonstration of this result, see Leautier (2016).

TABLE 1 SUMMARY OF ALBERTA'S MARKET STRUCTURE, GENERATION PORTFOLIO AND DEMAND

Panel A: Market Shares of Generation Capacity by Firm (in %)						
	TransCanada	TransAlta	ENMAX	ATCO	Capital Power	Fringe
2016	16.5	12.1	16.9	10.4	10.8	33.3

Panel B: Market Shares of Electricity Generation Capacity by Fuel Type (in MWs (%))					
	Coal	Natural Gas	Wind	Hydro	Other
2016	6,273.00 (38.0)	7,323.35 (44.3)	1,490.80 (9.0)	916.35 (5.5)	520.41 (3.2)

Panel C: Market Shares of Electricity Generation by Fuel Type (in %)					
	Coal	Natural Gas	Wind	Hydro	Other
2016	50.2	39.4	5.2	2.1	3.1

Panel D: Electric Sales by Consumer Group (in %)				
	Residential	Farm	Commercial	Industrial
2016	18.4	3.5	27.5	50.6

Notes: Data on generation capacity by firm are obtained from the Alberta Market Surveillance Administrator. Generation capacity and production data and electricity consumption data are obtained from the Alberta Utility Commission.

Alberta has three unique attributes that are important to consider. First, as demonstrated in Table 1, commercial and industrial consumers make up 78 per cent of electricity demand. Unlike other jurisdictions, residential demand is a small portion of electricity demand. Second, there is a sizable amount of natural gas capacity that comes in the form of co-generation. Co-generation produces steam and electricity for industrial use on site and sells any excess electricity to the wholesale electricity market. In 2016, there was 4,742.7 MWs of natural gas co-generation capacity, reflecting 65 per cent of all natural gas capacity and 29 per cent of market capacity. Third, relative to other markets, Alberta is an isolated market. Alberta has import capacity of 950 MWs and 153 MWs from British Columbia/Montana and Saskatchewan, respectively. Imports had the maximum capability to supply only 12 per cent of average market demand in 2016 (9,057 MWs) (AUC, 2017).

Alberta's electricity market is quickly evolving. All existing coal capacity is mandated to be retired by 2030.[4] As shown in Table 1, this reflects a large portion of the market's generation capacity and output. It is expected that a large number of the coal generation facilities will be converted to natural gas generation units in the near term. In addition, recent provincial policy sets a requirement that 30 per cent of electricity output in Alberta will come from renewable energy sources by 2030. The government is supporting the entry of renewable capacity via its Renewable Electricity Program (AESO, 2016b). The more stringent carbon pricing policy increases the costs of generating from higher emission technologies (e.g., coal), reducing the profitability of these technologies (Government of Alberta, 2016b, Brown et al., 2017). While Alberta's market is currently relatively isolated, the Alberta Electric System Operator is carrying out a study that analyzes a potential increase in integration of Alberta's electricity market with neighbouring provinces (British Columbia in particular) (AESO, 2016c). This has the potential to change the dynamics of Alberta's market going forward.[5]

Finally, as will be discussed below, accurate demand forecasts are critical in capacity markets. Generation capacity investments reflect long-term (15- to 30-year) commitments. Consequently,

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4 This reflects a combination of the federal coal regulations and Alberta's accelerated coal phase-out policy. For additional details, see AESO (2017a).

5 See Wolak (2015) for a detailed discussion of the potential impacts of transmission investment in Alberta.

inaccurate estimates in demand growth can create long-term distortions. Regulators have a challenging task of forecasting future demand. In addition to the need to replace retiring electricity generation facilities, Alberta anticipates a growth in electricity demand. This electricity demand growth is sensitive to the growth in industrial demand. This requires undertaking the challenging task of establishing long-run crude oil price forecasts (AESO, 2017a). This unique attribute of Alberta's market will prove to be an important complication and point of emphasis in the design of Alberta's capacity market.

ENERGY-ONLY VERSUS CAPACITY MARKETS

In the face of these numerous changes, the Alberta government has chosen to move from an energy-only to a capacity market design. Both energy-only and capacity market designs have proven to be capable of promoting sufficient investment in generation resources to meet electricity demand (Bushnell et al., 2017). However, it is important to recognize that each market design has its own advantages and disadvantages.

In principle, energy-only markets that are allowed to deliver large price spikes during hours of scarce supply can signal the profitability of new investment and promote resource adequacy. This may be feasible in an environment with limited restrictions on hourly energy market prices, well-defined markets, and a predictable and stable regulatory policy environment with limited out-of-market subsidies to certain resources.

Energy-only market designs are often viewed as the most economically efficient because they provide clear market price signals and firms (not consumers) internalize the risk of investing in generation assets (Hogan, 2005). However, with a growing penetration of renewables that have zero marginal cost of production, historically low natural gas prices and government policies that provide subsidies to certain technologies, there is more uncertainty in firms' abilities to recover their cost of capacity investment. This is not to suggest that a well-designed energy-only market cannot be successful at attracting investment in this environment, but from a policy-maker's perspective there is more uncertainty in the ability of this market design to promote electricity market reliability.[6]

Unlike numerous other jurisdictions, Texas, Australia's National Electricity Market and Germany have chosen to continue to operate as energy-only market designs in the face of a growing penetration of renewables (Jenkin et al., 2016).[7] Similar to Alberta, Texas's power market is facing substantial changes. Recently announced retirements of natural gas and coal generators are raising concerns that capacity reserve margins will drop below the regulators' targeted capacity reserve margin (Platts, 2017). Further, on Nov. 7, 2017, the Exelon Corporation's subsidiary, ExGen Texas Power (EGTP), filed for Chapter 11 bankruptcy for its power generation facilities in Texas, saying that "historically low power prices within Texas have created challenging market conditions for all power generators" (Exelon, 2017). Time will determine if these markets are able to attract sufficient investment in this environment.

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6 If Alberta maintained its energy-only market design, the wholesale electricity market price cap (currently at $999.99/MWh) would likely have to increase in order to ensure resource adequacy. AESO (2016a) forecasts the price cap would have to be elevated to at least $5,000/MWh to promote sufficient investment.

7 It is important to note that these market designs are heterogeneous, with their own unique attributes. I simply refer to them as energy-only markets because they do not have an explicit capacity payment mechanism.

Supporters of capacity markets advocate that they: (i) alleviate under-investment associated with energy-only markets and solve the missing money problem; (ii) provide more revenue certainty, lowering the cost of capital and promoting electricity market reliability; and (iii) reduce wholesale market price volatility. However, critiques of capacity markets argue that these market designs are: (i) prohibitively complex, costly to operate and rely on administrative parameters; (ii) yield excessive capacity investment due to risk-averse regulators creating a missing money problem they were aiming to solve and suppressing price signals in energy markets; and (iii) inaccurately assign capacity value to certain resources (e.g., imports and renewables).

There are important trade-offs in each market design. Well-designed energy-only markets arguably provide clearer, more economically efficient price signals. These market price signals are likely to become increasingly important as intermittent renewables and demand-side flexibility increase. However, with political limitations on the degree of price spikes and a growing penetration of renewables, energy-only markets come with more uncertainty in ensuring there is sufficient investment, price volatility and risk from a policy-maker's perspective. A well-designed capacity market can potentially provide more certainty in regards to investment and system reliability, while maintaining important energy market price signals via carefully designed hourly (or sub-hourly) energy markets. However, capacity markets are complex, expensive to design and operate, and have been the subject of substantial scrutiny for the administrative nature of their design.

COMMON FEATURES OF CAPACITY MARKETS

There are numerous capacity market designs utilized worldwide, each with its own unique attributes. In this section, I briefly outline the core common features of capacity markets.[8] While the precise details of Alberta's capacity market are uncertain at this point, it is anticipated that Alberta will adopt the central components of these commonly used capacity market designs.

Capacity markets are typically designed as an auction run by the system operator who co-ordinates electricity markets (e.g., the Alberta Electric System Operator (AESO)). The system operator decides how much of the capacity product it wants to purchase in the auction, forming a capacity demand curve. Recall that the capacity product reflects the potential to generate electricity at some specified time in the future. The capacity product can be supplied by existing generation resources, as well as from new generation resources. Capacity markets typically occur several years in advance of the subsequent hourly energy markets in which these resources are called upon to provide energy services. This provides new generation resources with the time to construct new assets.

Firms that can provide the capacity product submit bids into the capacity auction. These bids reflect the price at which they are willing to make their generation capacity available in future hourly energy markets over a specified period (e.g., a delivery year). More specifically, in a competitive market, these bids reflect the cost of providing the capacity product, net of the expected earnings in subsequent energy markets.[9] As an example, consider a new simple cycle

8 For a detailed review of capacity market designs, see Pfeifenberger et al., (2009) and Bushnell et al., (2016).

9 This abstracts away from firms' abilities to exercise market power to raise the capacity auction price above the level that would prevail in a perfectly competitive market.

natural gas turbine (SCGT) asset bidding in the capacity market.[10] The AESO estimates that the cost of new entry of a benchmark SCGT asset, net of its expected earnings in subsequent hourly markets, ranges from approximately \$156 to \$288 per MW-day (AESO, 2017b).

The system operator takes the bids submitted into the capacity auction and constructs an upward sloping supply curve. The capacity market price is set at the intersection of the capacity demand and supply curves. Firms that submitted bids for their capacity products at or below this price "win" and are paid the prevailing capacity price. These "winning" bidders are compensated for committing to provide the capacity product over the delivery year. However, this compensation comes with the requirement (referred to as a performance obligation) that the capacity must be made available to supply electricity in subsequent hourly energy markets during high-demand (stress) periods. If assets receiving capacity payments are not available during these high-demand periods, these assets fail to meet the associated performance obligation and pay a sizable penalty (Bushnell et al., 2017). For a given capacity auction, these payments and the associated performance obligations can last as little as one year and as long as 15 years (CRA, 2017).

The precise nature of how the costs of the capacity market are passed down to consumers varies substantially by jurisdiction. Capacity costs are often allocated based on a consumer's consumption during the highest demand hours across the network (i.e., their peak load contribution) or their maximum hourly demand in a particular month (Alberta Energy, 2017b). However, in the context of residential consumers where measuring hourly consumption is often difficult, retailers have some discretion in how capacity costs are allocated to different groups of consumers. Regardless of the exact details, these rules are often based on a consumer group's contribution to peak demand across the network. [11]

While the precise details of capacity markets are complicated and a more detailed treatment is out of the scope of this paper, I will focus on two key components that are central to the operation of these markets. First is the determination of the capacity demand curve. In theory, this curve should represent consumers' willingness to pay for the capacity product (i.e., reflecting the willingness to pay for electricity market reliability). However, in practice it is very challenging to estimate consumers' willingness to pay for electricity market reliability. Consequently, the capacity demand curve is administratively set by the system operator.

Figure 1 presents an example of a commonly used downward sloping capacity demand curve and an upward sloping capacity supply curve. The market-clearing price arises at the intersection of the capacity demand and supply curves, where the capacity supply curve is formulated by ordering the bids submitted by firms in the capacity auction in order of least cost. To define the capacity demand curve, the regulator sets an installed reserve margin (IRM) that often reflects forecasted maximum electricity demand plus a conservative reserve margin (e.g., 15 per cent).[12] The demand curve is downward sloping, so that the willingness to pay for capacity decreases for capacity levels above the targeted IRM.

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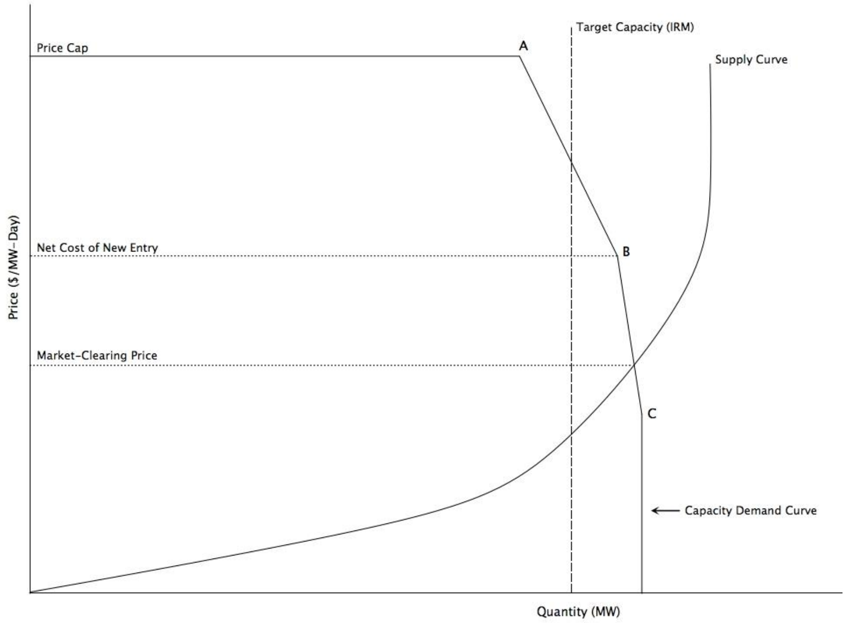
10 The AESO has proposed using a SCGT asset as the reference technology in Alberta (AESO, 2017b).

11 See Alberta Energy (2017b) for a discussion of the unique challenges in Alberta that need to be addressed when defining the capacity market cost allocation methodology.

12 There are numerous other approaches to set the resource adequacy standards that determine the IRM. The approaches often depend on the frequency of events where electricity demand exceeds available capacity. Alberta Energy (2017a) outlines the methodologies utilized in other jurisdictions such as the loss of load event, loss of load hours, normalized expected unserved energy, and the value of lost load threshold.

As demonstrated in Figure 1, the system operator has various administrative parameters to set when designing the capacity demand curve, including the maximum price (i.e., the price cap), the target capacity (IRM), and several inflection points represented by points A, B and C (Pfeifenberger et al., 2014). Point C represents the level of capacity (above the IRM) where the regulator is unwilling to pay for additional capacity at prices above $0. Point A reflects the level of capacity where the regulator is willing to pay the maximum price (price cap) for a minimum level of market capacity. Last, point B reflects the quantity of capacity where the regulator is willing to pay firms a capacity price equal to the net cost of new entry (Net CONE). The Net CONE reflects the cost of entry of a new combined-cycle natural gas asset, net of the revenues it expects to earn in subsequent hourly energy markets.[13]

FIGURE 1 CAPACITY DEMAND CURVE AND EQUILIBRIUM



A second critical component is the types of resources that can provide the capacity product. These resources must be able to generate electricity (or reduce demand) during periods of scarce production capacity. Common resources that can provide capacity products in capacity auctions are:

(i) Existing or new generation resources such as natural gas, coal, nuclear, biomass and hydro;

(ii) Demand response resources which reflect consumers' abilities to reduce electricity demand below their normal consumption patterns when called upon to do so; and

(iii) Variable (renewable) generation resources such as wind and solar.

The capacity product is defined to reflect a resource's ability to provide electricity services during hours where there is scarce production capacity in the market. As will be discussed in detail below, defining the reliability (capacity) value of certain resources is complicated by

13 See Pfeifenberger et al., (2014) for a detailed treatment of how regulators formulate capacity demand curves.

their intermittency or uncertain ability to supply electricity (or reduce demand) during hours of scarce supply when demand is high.

CHALLENGES AND LESSONS LEARNED

1. Designing the Capacity Demand Curve

The capacity demand curve is the primary tool that regulators have to impact the level of investment and capacity market outcomes. As a result, carefully designing the capacity demand curve is of central importance. One of the most common criticisms of capacity market designs is the tendency for risk-averse regulators to procure too much capacity by setting capacity demand parameters that are overly conservative (Newbery, 2015). This can create dynamic consequences that impact the performance of electricity markets, distort the critical capacity price signal, and undermine the central objective of capacity markets which aim to eliminate the missing money problem.

First, excess capacity procurement is expensive. The costs of idle generation capacity that is not necessary to ensure market reliability are passed down to consumers. Second, excess capacity suppresses prices in subsequent hourly electricity markets. Because bids in a competitive capacity auction reflect the cost of capacity net of expected earnings in these hourly markets, this elevates future capacity prices and the market's reliance on capacity payments. This increased reliance on the capacity auction increases the pressure placed on regulators to get these capacity demand parameters right in subsequent capacity markets. Critiques of capacity markets often view this problem as creating a missing money problem that capacity markets were put in place to solve. Further, it is often thought that if regulators over-procure capacity, they can simply solve the problem by procuring less in subsequent capacity auctions. The continual adjustment of the regulatory parameters in capacity markets undermines this capacity price signal and creates uncertainty for investors looking to make large long-term capital investments.

Third, the provincial and federal governments are actively investigating the potential value of increased integration of Alberta's electricity market with neighbouring British Columbia (AESO, 2016c). Increased regional integration can assist in integrating intermittent generation across wider geographical markets. Excessive procurement of capacity within Alberta suppresses hourly electricity prices to inefficiently low levels. This reduces the arbitrage profits of importing supply from neighbouring British Columbia, reducing the commercial incentive for such interconnections.[14]

To summarize, the multitude of capacity demand parameters provides regulators with substantial flexibility, but it also creates substantial room for error. This flexibility is often viewed as a benefit, but it can distort important market price signals. Designing an appropriate capacity demand curve is central to the success of a capacity market. This involves careful

[14] However, at the same time, excessive capacity procurement could elevate the capacity auction price paid to importers from British Columbia (if they are able to participate in the capacity auction). The net effect of these two forces on the profitability of additional interconnections depends largely on the assigned capacity value of imports, as well as the relative impact of suppressed electricity prices and elevated capacity auction prices.

deliberation over setting the critical capacity demand curve parameters.[15] An important point of emphasis in the context of Alberta's electricity market is forecasting peak electricity demand, which is critical in setting the installed reserve margin (recall Figure 1). Alberta's large industrial demand is tied closely to global economic factors such as crude oil prices. This creates unique challenges for the design of Alberta's capacity market. In addition, there is limited room for error because Alberta's electricity market is small. Errors that result in a single generation unit being built (e.g., a single 400 - 800 MW natural gas unit) beyond the amount need to ensure resource adequacy can have long-term consequences on the wholesale electricity market price signals. This is in contrast to other jurisdictions with capacity markets that cover large regional electricity markets that can more readily absorb excessive procurement.

2. Policy Uncertainty

The Alberta government has substantial control over the design and operation of its electricity market. While this can provide regulators and policy-makers with the ability to make important adjustments to the market, it can also generate substantial policy uncertainty. Investors in generation capacity are deciding to make investments that can last 15 to 30 years. Policy uncertainty increases risk premiums on large-generation capacity investments as investors require more compensation for internalizing policy risk. This increases the cost of procuring capacity.

Further, the presence of policy uncertainty can impact which firms choose to invest in Alberta. Firms that are more familiar with Alberta's governance structure and electricity market may be more willing to internalize this risk and invest in Alberta. Increased market concentration raises concerns over firms' abilities to exercise market power, elevating prices above levels that would prevail in a perfectly competitive market.

It is critical that the government establish well-defined and detailed trajectories for Alberta's electricity market as a whole, not just its capacity market. While it is natural that new governments introduce new policies to address changes in the market environment, it is vital that these changes are done in a way that does not create undue policy uncertainty and damage investor confidence.

3. Capacity Value of Renewables and Co-generation

The capacity product reflects an energy resource's ability to generate electricity in subsequent energy markets (particularly during high-demand hours). More specifically, this reflects a resource's contribution to the reliability of the system and is central to a well-functioning capacity market. The capacity value of renewable generation is heavily debated due to its intermittent nature. Although renewable resources cannot be called upon to supply electricity in the sense that a natural gas generator can, these resources can still contribute to the network's reliability. The capacity value of these resources depends critically on location and the correlation of their electricity production with market demand. This is an important issue that needs to be considered in detail given the anticipated growth of renewables in Alberta.

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[15] Pfeifenberger et al., (2014) provide a detailed analysis of capacity demand curve parameters.

Estimating the capacity value of renewable resources is a challenging task. The existing methods are diverse and can result in a wide range of estimated capacity values for wind and solar resources. For example, the capacity value allocated to wind (solar) resources in capacity markets in the United States ranges from 12 per cent to 33 per cent (38 per cent to 100 per cent) of installed unit capacity.[16] These percentages reflect the relationship between expected generation from renewable assets and peak electricity demand. These sizable differences in the capacity value can have large impacts on the outcome of the capacity market and subsequently, on firms' investment decisions. Recent research has utilized well-established electricity market simulation models to estimate a renewable resource's contribution to the reliability of electricity network (e.g., Bothwell and Hobbs, 2017). Rather than establishing a single capacity value for wind and solar, regulators should utilize these robust methods to estimate a renewable resource's contribution to reliability when estimating its capacity value (e.g., based on its location and correlation with market demand and the output of other renewable resources). This avoids distorting important capacity and energy market price signals that drive investment.

The treatment of co-generation in Alberta's capacity market is also uncertain. Co-generation produces steam and electricity for industrial use on site and sells any excess electricity to the wholesale electricity market. Alberta is unique in that a large portion of its production capacity arises from co-generation facilities (29 per cent of market capacity in 2016). As a result, Alberta needs to clearly define how to treat co-generation in the capacity market.

Other jurisdictions have rulings related to "behind-the-meter" generation, such as Alberta's co-generation facilities (e.g., PJM Interconnection (2017)). In these jurisdictions, industrial consumers with co-generation facilities pay a portion of the capacity market costs based on their consumption during the system peak hour (where the system peak hour is the hour during which the usage was highest across the entire electricity market). Then, these industrial firms can bid their co-generation facility into the capacity auction and receive a capacity payment for this resource. This allows the industrial facility to effectively net out the cost of the capacity payment charged on their demand during the system peak hour. Alberta should adopt a similar treatment to deal with its large co-generation facilities, with specific language in the regulation to clearly spell out the participation of these resources in the capacity market.

4. Market Power Mitigation

Recall, Alberta's market has historically been an energy-only market where firms must recover both fixed and variable costs in hourly energy markets. Ideally, market prices could rise to a sufficiently high level during periods of scarce electricity supply in these markets to recover the fixed costs of capacity investment and provide a market signal for subsequent capacity investment. However, wholesale prices are capped at $999.99/MWh due to concerns over firms' abilities to exercise excessive market power and the controversy over large price spikes.

To avoid the classic missing money problem where firms are unable to recover their fixed costs in hourly energy markets, Alberta has permitted the execution of certain types of market power. More specifically, unlike other jurisdictions, firms are permitted to submit bids above their marginal cost of production with the explicit intention of raising prices (MSA, 2011).

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[16] For a detailed discussion on current methods used to estimate the capacity value of renewables and an analysis on alternative methods, see Bothwell and Hobbs (2017).

This form of market power execution is referred to as economic withholding. Firms are not permitted to undertake in collusive behaviour or physically withhold available production capacity from the market (MSA, 2011). Brown and Olmstead (2017) demonstrate that firms have historically exercised a sizable amount of market power in high-demand hours in Alberta's wholesale market.

The argument for allowing a certain degree of market power in Alberta's energy-only market is to ensure that firms are able to recover their large fixed cost of investing in generation assets in these hourly markets. The market has relied on the entry of new generation assets to moderate long-run market prices and limit firms' abilities to exercise market power (Olmstead and Ayres, 2014). In previous years, if firms submitted bids in hourly energy markets equal to their marginal cost of production (i.e., exercised no market power), they would often be unable to recover their fixed cost of capacity investment (Brown and Olmstead, 2017).

In a capacity market design, the argument for permitting market power in hourly wholesale electricity markets is less clear. The capacity market structure replaces the execution of market power in wholesale electricity markets as a source of revenues to recover the fixed costs of investment. There have been heated debates regarding whether firms should be able to exercise market power in Alberta's capacity market design (MSA, 2017b). It is unclear why permitting market power execution in a capacity market design is defensible.

The introduction of a capacity market should be coupled with regulations that limit firms' abilities to exercise market power and raise market prices. This can be done by imposing bid mitigation methods that restrict the bids that firms submit in hourly wholesale energy markets to reflect their (estimated) costs of supplying electricity.[17] This approach is not without its own caveats. First, this places a heavy burden on regulators to accurately estimate firms' marginal cost of supplying electricity. Second, while this limits firms' abilities to affect hourly market prices by behaving strategically, this can impact firms' investment decisions.[18] Despite these concerns, conditional on implementing a capacity market, it is not clear that there is a benefit to permitting market power execution in hourly energy markets.

5. The Importance of Maintaining Price Signals

The hourly energy markets should ensure that prices reflect the value of supplying energy services. Subsequently, the capacity auction reflects the revenues that firms need to earn in excess of the earnings provided in hourly energy markets to cover the fixed costs of new and existing generation assets. The capacity market effectively operates as a market that provides revenues to ensure system reliability, net of the expected earnings in subsequent hourly energy markets. More broadly, in designing the capacity market, regulators need to evaluate the electricity system as a whole and assess how the capacity auction fits in with the larger system.

It is likely that there will be a large increase in renewable capacity in Alberta with important location-based characteristics. In addition, due to technological innovation, there is a growing emphasis on distributed energy resources in electricity markets worldwide that take the form of

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[17] For a detailed discussion of bid mitigation, see MSA (2017a).

[18] For a detailed discussion of the issues with bid mitigation and cost-based designs, see Munoz et al., (2017).

more flexible electricity demand, rooftop solar panels, energy efficiency and electric vehicles.[19] For example, in February 2017, the Alberta government announced a $36 million rebate program for the installation of rooftop solar (Government of Alberta, 2017c).

The value of price signals in hourly energy markets become even more important in this environment. Consequently, it is critical that as regulators design the core features of the capacity market, they simultaneously consider other elements of Alberta's electricity market design and how these components fit together as a system. For example, similar to an energy-only market design, hourly prices remain a critical signal of the instantaneous value of electricity in a capacity market design. During periods of scarce supply, prices should be allowed to rise to levels that reflect this scarcity. This increases the expected revenues from energy markets and in turn lowers the capacity market price which operates as a market that provides residual revenues (net of energy market revenues). Over time, if the value of energy services is accurately priced, the capacity auction will become a less central component of the market.

CONCLUSIONS

Alberta's electricity market is currently undergoing a period of substantial transition. In 2016, the Alberta government announced policies that include a mandated phase-out of all coal generation by 2030, more stringent environmental regulations on carbon emissions via a new carbon pricing policy and the implementation of the Renewable Electricity Program aimed at a target of 30 per cent of electricity supply coming from renewable generation by 2030 (Government of Alberta, 2017a,b). Coupled with these changes, the government announced a change in Alberta's electricity market design with a movement from an energy-only market to a capacity market design (Government of Alberta, 2016).

While capacity markets have been promoted for their ability to alleviate concerns of under-investment in energy-only market designs, they are not without their own trade-offs. Regulators in Alberta can utilize the experiences in other jurisdictions with capacity markets to avoid common mistakes and pitfalls in capacity markets. While I abstracted from many important details related to the design of a capacity market, this paper provides a summary of several key issues that should be considered when designing and evaluating the validity of capacity market design. The key points are summarized as follows:

1. The Careful Design of the Capacity Demand Curve

The capacity demand curve is arguably the most important instrument in ensuring the capacity market operates effectively. Errors in the design of the capacity demand curve can create numerous dynamic inefficiencies. Missteps in the design of the capacity demand curve are particularly damaging in Alberta because the market is relatively small and isolated. An important point of emphasis is the inherent uncertainty in demand growth in Alberta as electricity demand is closely tied with variations in global crude oil prices. This poses a unique

[19] For additional details on pricing with a growing penetration of distributed energy resources, see MIT Energy Initiative (2017).

challenge for Alberta regulators. Despite these challenges, regulators in Alberta can utilize the experience from other jurisdictions to carefully design capacity demand.[20]

2. Establishing Certainty in Policy and Governance

The policy and governance structure in Alberta provides policy-makers with the opportunity to implement new policies quickly to adapt to changes in market forces. However, this can generate substantial uncertainty, lowering investor confidence. Incumbent firms that are more familiar with investing in Alberta may be more willing to invest in this environment. This can raise market concentration, elevating concerns of market power in an already concentrated environment. It is critical that the current government establishes well-defined, detailed and clear trajectories for Alberta's electricity market design going forward. Undue policy uncertainty can undermine the success of any electricity market design.

3. Maintaining Price Signals

With the expected growth in flexible demand and intermittent renewable resources, getting prices right in hourly (or sub-hourly) energy markets is becoming increasingly important with or without a capacity market. Regulators shouldn't be concerned with how much revenue comes from the capacity versus hourly energy markets. Alternatively, energy prices should reflect the value of energy services, allowing for high(er) prices during periods of scarce supply of electricity. Then, the capacity market should provide revenue to cover the capacity costs of new or existing generation assets, net of the expected earnings in subsequent hourly energy markets. Consequently, when designing the future of Alberta's electricity market, regulators need to carefully design the capacity auction and simultaneously consider adjusting aspects of the existing hourly energy markets. This can affect the types of resources that invest in Alberta, as well as the cost of ensuring system reliability.

4. Trade-offs with Both Energy-Only versus Capacity Market Designs

It is important to recognize that both energy-only and capacity market designs have their own pros and cons. Electricity markets are very complex systems with numerous moving parts. Energy-only markets are arguably more economically efficient with cleaner price signals. Capacity markets are often viewed as costly to operate, complex, based on administrative parameters and prone to errors that can impact important market price signals. However, given restrictions on the size of price spikes in hourly energy markets, risk-averse investors and a growing penetration of intermittent resources, there is more uncertainty in the ability of energy-only markets to promote investment, raising concerns over the reliability of electricity supply. A capacity market can promote more certainty in resource adequacy, but at a potentially higher cost. The decision to adopt an energy-only or a capacity market is driven largely by risk preferences, policy objectives and expectations of the trajectory of generation unit investments and retirements.

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[20] See Pfeifenberger et al., (2014) for commonly used capacity demand curves.

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